ATIKOKAN HYDRO INC.

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May 24, 2012

Kirsten Walli,
Board Secretary
Ontario Energy Board
P.O. Box 2319
27th Floor 2300 Yonge Street
Toronto, ON
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Dear Ms. Walli:

Re: REPLY SUBMISSION
OF ATIKOKAN HYDRO INC.
Board File No. EB-2011-0293

Atikokan Hydro Inc. is pleased to submit its reply submission regarding EB-2011-0293 Cost of Service application.

The Application includes the following Exhibits:
Atikokan Reply 20120524.pdf
Atikokan PILS Reconciliation 2001 – 2012.xls
Atikokan PILS Continuity Schedule 2001-2012.xls

These responses have been filed electronically with the Board today and two (2) paper copies will be delivered to the Board Secretary.

If you require further information please contact me.

Regards,

Wilf Thorburn

Wilf Thorburn
CEO Secretary/Treasurer
Atikokan Hydro Inc.

EB-2011-0293

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an Application by Atikokan Hydro Inc. to the Ontario Energy Board for an Order approving just and reasonable rates and other charges, effective May 1, 2012.

REPLY SUBMISSION
OF ATIKOKAN HYDRO INC.

Delivered May 24, 2012

INTRODUCTION

1. Atikokan Hydro Inc. ("Atikokan", "Atikokan Hydro" or the "Applicant") owns and operates the electricity distribution system located in the Town of Atikokan.

2. On September 30, 2011, Atikokan filed an application with the Ontario Energy Board ("the Board") under section 78 of the *Ontario Energy Board Act, 1998, S.O. 1998,* c. 15, (Schedule B), seeking approval for changes to the rates that Atikokan charges for electricity distribution to be effective May 1, 2012. The Board has assigned the file number EB-2011-0293 to this Application (the "Application").

3. On October 24, 2011, the Board issued a letter to Atikokan identifying certain additional evidence that needed to be filed before the Board would consider the Application. Atikokan filed the requested additional evidence on December 14, 2011.

4. The Board issued a Notice of Application and Hearing dated December 22, 2011. The Vulnerable Energy Consumers Coalition ("VECC") applied for intervenor status and cost eligibility. No objections were received. The Board determined that VECC would be granted intervenor status and is eligible to apply for an award of costs under the Board's Practice and Direction on Cost Awards.

5. In its Notice of Application and Hearing, the Board indicated its intention to consider the Application by way of a written hearing. The Board issued Procedural Order No. 1 on January 13, 2012. In Procedural Order No. 1, the Board allowed for an initial round of discovery through written interrogatories.

6. On January 31, 2012, Board staff filed its interrogatories with Atikokan; VECC filed its interrogatories on February 3, 2012. On February 23, 2012 Atikokan filed a letter requesting an extension for filing its interrogatory responses to February 29, 2012. The Board responded by way of a letter issued on February 24, 2012 granting the extension. Atikokan filed its interrogatory responses on March 2, 2012.

7. On March 16, 2012, the Board issued Procedural Order No. 2 and acknowledged that Atikokan had responded to a relatively large number of interrogatories; however he Board was of the view that a second round of interrogatories was necessary to complete the record. This was due to amended and, in some instances, new, evidence placed on the record in the first round.

8. Procedural Order No. 2 outlined the following process to be followed for this Application:

   a) A second round of interrogatories was to be delivered to the Atikokan by Board staff and intervenors by March 28, 2012;
   b) Atikokan was to file its responses to those interrogatories by April 11, 2012;
   c) Atikokan was to file an Argument-in-Chief with the Board and intervenors by April 20, 2012; and
   d) The Board staff submission to the Board is due May 4, 2012; the intervenor submission to the Board is due May 9, 2012; and the Applicant's reply submission is due May 18, 2010.

9. In accordance with the Board's Order, Board staff and intervenors submitted the second round of interrogatories to Atikokan on March 28, 2012.

10. Atikokan's responses to the second round of interrogatories were filed with the Board and provided to intervenors on April 11, 2012.

11. Atikokan delivered its Argument-in-Chief on April 20, 2012. In its Argument-in-Chief, beginning at page 6, paragraph 18, Atikokan discussed the changes it had made to the relief sought in its Application through the interrogatory process. As noted at paragraph 20 of the Argument-in-Chief, in total, the revisions mentioned above and discussed in further detail below result in a revised proposed Service Revenue Requirement of $1,586,820, an increase of $7,217 over the Service Revenue Requirement of $1,579,603 proposed in the Application. With revenue offsets of $125,235 (this value has remained constant through the interrogatory process); the revised Base Revenue Requirement is $1,461,585.

12. The Board staff and VECC submissions were delivered on May 4, 2012 and May 9, 2012

respectively.

13. The record in this proceeding, consisting of comprehensive pre-filed evidence and responses to interrogatories, supports Atikokan's Application. The Application, with the adjustments set out in this submission, will provide the revenue requirement necessary to sustain Atikokan's capital, operating and maintenance programs in a manner that continues to provide safe and reliable distribution of electricity in the Town of Atikokan.

14. Throughout the Application process, Atikokan has been conscious of and focused on minimizing impacts on its customers. In the Application, Atikokan proposed that a rate mitigation plan be implemented to limit the bill impacts for Residential customers using 800 kWh per month to a bill increase of 10%. The proposed rate mitigation plan included a rate migration rate rider (i.e. a credit to Residential customers) plus a proposal to defer the disposition of the 2010 Group 1 and 2 deferral and variance account balances until the 2013 IRM. The implementation of the plan would limit the bill impacts for a Residential customer using 800 kWh per month to 10%.

15. In response to a Board staff interrogatory, Atikokan revised its impact calculations to reflect typical Residential consumption in the Atikokan service area of 581 kWh per month. If the Application, as filed and with the modifications proposed by Atikokan, is approved by the Board, a Residential customer consuming 581 kWh per month (as discussed below, this would represent a more typical Atikokan Residential customer) would have a total bill increase of 10%, and a General Service < 50 kW customer using 2,000 kWh per month would have a total bill increase of 8.64%.

16. On the following pages, Atikokan has set out its reply to the Board staff and VECC submissions. The reply generally follows the approach used by Board staff in that it follows the order of exhibits in Atikokan Hydro's Application and as documented in the Board's current *Filing Requirements for Transmission and Distribution Applications*, issued June 22, 2011 (the "Filing Requirements"). The order is as follows:

    1. Administration
    2. Rate Base and Capital Expenditures
    3. Operating Revenues and Load Forecast
    4. Operating Expenses
    5. Cost of Capital
    6. Cost Allocation
    7. Rate Design
    8. Deferral and Variance Accounts

9. Other Matters

17. As noted in its Argument-in-Chief, Atikokan maintains that its proposed revenue requirement has been determined appropriately; that its proposed capital and OM&A programs for the 2012 Test Year are reasonable and supported by the evidence in this proceeding; and that the resulting distribution rates are fair and reasonable. Atikokan maintains its request for relief as set out in its Argument-in-Chief subject to any revisions set out in this reply submission.

1. ADMINISTRATION:

- **Effective Date of Rates.**

18. Atikokan requested in its Application that its rates be effective May 1, 2012.

- *Board staff and VECC submissions*

19. Neither Board staff nor VECC opposed the Atikokan request.

- *Atikokan's reply*

20. Atikokan reiterates its request for an effective date of May 1, 2012. Atikokan recognizes that it will not have the Board's final Rate Order in time for May 1st implementation. Accordingly, as part of its Draft Rate Order to be filed following the issuance of the Board's Decision, Atikokan will prepare an appropriate rider that will enable it to recover the incremental revenue requirement for the period commencing May 1st and concluding on the date preceding the implementation date of the new Rate Order.

21. While VECC does not oppose Atikokan's request for a May 1st effective date, VECC comments on Board staff's suggestion that Atikokan is operating under financial distress. VECC states (in part) that it:

> "…does take issue with the characterization of Atikokan Hydro Inc. (Atikokan) as being a utility under financial duress. The comments made in Staff's submission (see page 26) appear to be due to a note in Atikokan's 2010 financial statements under the heading "Going Concern." In essence the note reflects the auditors concerns due to losses Atikokan has incurred. VECC notes that the Applicant has not applied for any special consideration or relief due to reasons of financial duress. While the reasons for Atikokan's inability to earn its regulated return remain unclear, it is the clear that the Utility has not been operating under financial duress over the past four years. In fact, it has made major discretionary expenditures on buildings, vehicles and increased its FTEs. VECC submits it would be unfair to ratepayers to explicitly or implicitly provide special consideration or relief that the Applicant has not sought and which is not supported in evidence."

22. As noted in Board staff Interrogatory 37 (in reference to Exhibit 1/Tab 3/Appendix F – Atikokan's Audited Financial Statements for the year ended December 31, 2010), the Financial Statements contain the following "Going Concern" note:

> "The continuation of the Corporation is dependent upon the continuing availability of operating and long term financing and achieving a profitable level of operation through the ability to increase rates that are currently regulated by the Minister of Energy and the Ontario Energy Board."

23. As discussed in Atikokan's response to that interrogatory. the revenue requirement model

(updated as per Board staff IR#58) indicates that Atikokan Hydro will forecast a 38k gain for 2011 assuming MIFRS and a 249k net income for 2012, based on the rates being approved in this Application [prior to rate mitigation]. However, Atikokan noted that the 2011 Financial Statements would be closed using CGAAP. Therefore, realistically as per Atikokan Hydro's original Application, Atikokan Hydro was forecasted to have a $7,000 loss for the 2011 fiscal year.

24. In Board staff IR#64, Board staff requested further information on Atikokan's expected loss for the 2011 year. Atikokan advised that throughout the Application and particularly in the deficiency descriptions, Atikokan had indicated that it faces significant challenges to operate at existing rate levels. Preliminary work on its audited 2011 financial statements showed a significantly greater loss than forecast in the current Application [$85,000]. Revenue in both the Residential and GS<50 kW classes was down in both fixed and volumetric service charges, and revenue for these classes as compared to 2010 would be down by $102,992.

25. Atikokan went on to advise that in terms of the going forward comment, Atikokan expected that with losses greater than forecast, there would be a similar comment to indicate that Atikokan will need to increase its rates or decrease its costs to continue to be viable. Atikokan has reviewed its costs several times. Atikokan is faced with rising costs for many items including operating the smart meters, with same or fewer customers to bear those costs. As the Board is aware, Atikokan's average Residential customer consumption is lower than the standard 800 kWh customer consumption. The following table [page 9 of Atikokan's response to Board staff Interrogatory #64] does support the suggestion that Atikokan is in financial duress:

	2011	(Note 2) 2010	Difference
Revenue			
Sale of energy	$0	$0	
Distribution revenue	1,076,223	1,146,051	-69,828
Rent from electric property	34,911	34,911	0
Late payment charges	4,809	6,024	-1,215
Miscellaneous revenue	105,748	133,910	-28,162
Demand management program revenue	0	0	0
Interest and dividend income	11,012	14,799	-3,787
Total	1,232,703	1,335,695	**-102,992**
Expenses			
Administration	514,543	450,248	64,295
Amortization	198,823	221,088	-22,265
Billing and collecting	156,366	130,786	25,580
Distribution expense operation	208,516	323,096	-114,580
Distribution expense maintenance	137,495	120,699	16,796
Energy cost	0	0	0
Interest on long-term debt	93,508	83,048	10,460
Other interest expense	4,760	10,685	-5,925
Demand management program expense	0	0	0
Total	1,314,011	1,339,650	**-25,639**

26. Atikokan is not seeking special treatment in this Application. It does, however, seek approval of a revenue requirement and rates that will allow it an opportunity to recover, among other items, the costs of operating and maintaining the utility, the revenue requirement associated with its proposed capital expenditures and a return on capital reflective of the Board's applicable cost of capital parameters.

2. RATE BASE AND CAPITAL EXPENDITURES:

- **2012 Test Year Rate Base and Capital Expenditures**

27. As discussed at Exhibit 2; Tab 1; Schedule 1; Page 1, Atikokan's proposed rate base for the 2012 Test Year was $2,913,786. During the interrogatory process the rate base has increased by $127,838 to $3,041,625 for the following three reasons:

- The 2011 bridge year was moved from CGAAP to MIFRS which caused the rate base to increase by $34,914. This essentially reflects a one year change in deprecation resulting from higher useful life under MIFRS (please see Atikokan's response to Board Staff Interrogatory #45);
- An increase in OM&A of $45,229 resulting from OMERS expenses previously recorded in a deferral and variance account which impacts the rate base by $6,784 reflecting the impact on working capital being 15% of $45,229 (please see Atikokan's response to Board Staff Interrogatory #36); and
- As a result of using the Board's smart meter model, Atikokan reviewed the smart meter costs and determined that capital should move from the computer hardware asset class to the meter asset class. In addition, it was determined that in the original Application the 2012 continuity schedules assumed 2011 smart meter opening balance values in the 2012 opening balances instead of 2012 values. These corrections (please see Atikokan's response to Board Staff Interrogatory #38) increased the rate base by $86,140.

28. Atikokan's calculations of its revised rate base are set out in its Argument-in-Chief, in a table provided at paragraph 22.

- *Board staff and VECC submissions*

29. Board staff took no issue with Atikokan's 2012 rate base, as revised. Further, Board staff submitted that Atikokan's Asset Management Plan "is generally adequate and supportive of its capital projects and expenditures."[1]

30. While VECC had no with Atikokan's adjustments to its rate base, it submitted that the Board

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[1] Staff submission, at p.4

should adjust Atikokan's rate base downward by between $8,000 and $30,000.[2] VECC bases this request on changes in Atikokan's capitalization policy; improving system reliability (with the exception of losses), which in VECC's view suggests that a reduction in rate base will not lead to imminent dangers to system operations; a declining population base in Atikokan's service area and the loss of major customers; and Atikokan's spending on buildings and trucks in the 2008-2012 period. VECC suggests that questions of prudence are raised in light of Atikokan's spending.

31. VECC suggests reductions in Accounts 1908 (Building and Fixtures) and 1940 (Tools and Garage Equipment), and in Atikokan's computer budget.

- *Atikokan's reply*

32. Atikokan submits that with one exception discussed below, the reductions proposed by VECC are neither reasonable nor appropriate. The capital expenditures on the buildings and trucks were capital projects that Atikokan included in its 2008 Cost of Service application, and that were approved by the Board at that time. Atikokan respects VECC's concern with the prudence of Atikokan's expenditures, but despite a declining customer base, Atikokan requires the same level of fleet and buildings to service the town. In the same way that a reasonable staffing level is required, a reasonable utility fleet is needed in order to adequately and safely provide reliable service. As with any other electricity distributor, Atikokan requires specific equipment in order to carry on its operations. Atikokan's Board-approved expenditure on a new garage was prudent in that it replaced a garage that was no longer adequate to house larger modern equipment. Outside storage of this equipment would reduce its life span and therefore increase costs to Atikokan and its customers in the longer term. Atikokan also rejects VECC's implication that it is being imprudent in its Board-approved fleet expenditures. Atikokan maintains a 1982 truck in its fleet – Atikokan submits that there can be no question that it attempts to prolong the life of its fleet in order to ensure that any fleet expenditures are in fact necessary and prudent. As noted above, the fleet and garage expenditure were considered and approved by the Board in the context of Atikokan's 2008 cost of service application (Board File No. EB-2008-0014**)**. Atikokan also notes that VECC questioned the need for a new aerial device and a 3-bay garage in the 2008 proceeding – and more particularly, in VECC Interrogatory #9. At pages 8 and 9 of its

[2] VECC submission, p.2, para.2.2

Decision in Atikokan's 2008 cost of service application, in the "Capital Expenditures and Rate Base" section, the Board noted that "VECC submitted that Atikokan had explained the need for the new truck and the expanded equipment storage facilities."

33. With respect to VECC's comment that there is "there is room for a reduction in the computer budget for 2012 of $20,000 (12,000 for hardware and $8,000 for software)"[3], Atikokan submits that the amount budgeted for computer upgrades includes improvements identified in Atikokan's smart meter security audit, and they are important to the maintenance of safe, reliable and secure electricity distribution services to Atikokan's customers. The hardware and software being replaced are six years old, and beyond their useful lives. Computer hardware and software are critical to the operation of Atikokan Hydro and a computer failure would prevent essential data being received that supports customer service.

34. The one exception referred to above relates to the $8,500 expenditure on buildings in 2012 mentioned by VECC. The $8,500 allotted for buildings is for a new roof on Atikokan's administrative office building, as the existing roof is in need of repairs. Atikokan Hydro anticipated requesting tenders for repairs to the roof during the 2012 Test Year. In considering this matter, Atikokan and its affiliate Atikokan Enercom ("Enercom") have agreed that the roof repairs should be charged to Enercom. Accordingly, Atikokan agrees that the sum of $8,500 should be removed from its 2012 Test Year capital budget.

- **Working Capital Allowance**

35. As discussed in the Application, the rate base used by Atikokan for the purpose of calculating the revenue requirement is the average of the beginning and ending fixed asset and accumulated depreciation balances, plus a working capital allowance which is 15% of specific OM&A and cost of power accounts.

- *Board staff and VECC submissions*

36. Board staff acknowledged[4] that Atikokan "has used the default 15% formula, whereby the Working Capital Allowance ("WCA") is calculated as 15% of the sum of the cost of power plus controllable expenses. In response to interrogatories, Atikokan Hydro updated the

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[3] VECC Submission, p.4 para.2.9
[4] Board staff submission, at p.4

WCA to reflect the HOEP and RPP commodity rates documented in the Board's October 17, 2011 *Regulated Price Plan* Report as well as that change in OM&A for OMERS expense increases…." Board staff also acknowledged that Atikokan's proposal to use the default 15% factor is consistent with Board policy for 2012 rates. However, Board staff also noted that Atikokan Hydro does monthly billing for all of its customers, and that this is in contrast to most distributors who still bill most small consumption customers (i.e. Residential, GS < 50 kW) every two months. In Board staff's view, "the average service lag, one important factor in determining cash working capital requirements, would be expected to be much shorter for Atikokan Hydro than for most utilities. Board staff observes that the 15% is, in all likelihood, overly generous for Atikokan Hydro." With the Board having recently announced that, for 2013 rates, the default WCA factor is being reduced to 13%.[5] Board staff submits that "one option would be for the Board to direct Atikokan Hydro to adopt the 13% factor, in recognition in part that its cash working capital requirements should be reduced due to monthly billing."

37. VECC makes a similar submission, and argues that Atikokan should be required to use the 13% value for the calculation of the working capital allowance.

- *Atikokan's reply*

38. In its application, Atikokan Hydro used the default value of 15% in calculating its working capital allowance. This is consistent with the Filing Requirements. It is only with the 2013 group of cost of service filers that the default value will be reduced to 13%, and Atikokan is not aware of any provision in the Board's letter of April 12, 2012 or in the Filing Requirements that would provide for the retroactive application of that 2013 value. Atikokan Hydro does not have any evidence to support the assertion that 13% would be appropriate in its circumstances, nor do Board staff and VECC, and imposing the 13% value on Atikokan at this time would lock the lower value into place for the next four years. Atikokan Hydro understands that it may need to either conduct a study or use the default value in place at the time of its next cost of service application (expected for 2016). At this time, however, Atikokan submits that it is inappropriate to arbitrarily impose the 2013 value in its 2012 rebasing.

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[5] Board letter of April 12, 2012, http://www.ontarioenergyboard.ca/OEB/_Documents/2013EDR/Letter_WCA_for_2013_Filing_Requirements_20120412.pdf

3. OPERATING REVENUES AND LOAD FORECAST

- **Load Forecast**

39. Atikokan Hydro has used a 2012 test year forecast of 25,592,783 purchased system kWh and 23,593,125 billed kWh. Atikokan has proposed no changes in its load forecast or its customer/connection forecast from that used in its Application.

- *Board staff and VECC submissions*

40. As Board staff note at page 5 of their submission, "Atikokan Hydro used a commonly accepted approach for a regression-based load forecast for demand for all classes, in aggregate." Board staff go on to note that "Atikokan Hydro has used a linear regression model that has evolved and been accepted by the Board in previous cost of service cases. The general approach is to regress monthly kWhs based on economic activity, days in the month, Heating Degree Days ("HDD"), Cooling Degree Days ("CDD") Spring/Fall binary "flag", CDM and other variables as necessary. This modeling approach attempts to estimate the influence of key determinants – such as customer base, economic activity, and seasonal and weather variations on realized demand. The estimated parameters are then used in the model along with forecasted exogenous variables for the test period to estimate a weather-normalized demand."

41. Board staff advises that they generally take "no issue with Atikokan Hydro's approach, although it observes that, once the demand of the Intermediate customer is removed from the historical data, demand is relatively flat." They discuss Atikokan's response to VECC Interrogatory 8(b) in which Atikokan filed an alternative regression model that excluded the historical demand and consumption of the previous Intermediate customer (and the load forecast resulting from the alternative model), and they note that while Atikokan is not proposing to change its load forecast, the forecast from the response to VECC IR 8(c) may be more reasonable.

42. With respect to the load forecast as it relates to the Street Lighting class, Board staff question Atikokan's methodology, but accept that "the resulting rates will be compensatory based on the data, even if somewhat 'wrong'." Board staff submits that "the data is anomalous and the utility needs to better analyze and document its load data at its next cost of service rebasing application."

43. In its submission, VECC describes Atikokan's load forecasting methodology, and submits that "VECC does not have any issues with the overall approach taken by Atikokan nor with the multifactor regression model that it has developed. The model has a high Adjusted R-Squared value and all the proposed explanatory variables are both statistically significant and have intuitively correct coefficients[6]". VECC does not support the Board staff suggestion with respect to the use of the alternative load forecast arising out of the regression model that excludes the Intermediate Class loads from the historical analysis, for the reasons given at paragraph 3.3 of the VECC submission.

44. With respect to Atikokan's billed energy volumes for 2011 and 2012, VECC's only concern appears to relate to CDM. Specifically, at paragraph 3.5 of its submission, VECC expresses "concerns regarding the reasonableness of Atikokan's 0.2 GWh adjustment for 2012. However, given the LRAM true-up process established in the Board's recently released CDM Guidelines[7], VECC does not see any need to alter Atikokan's proposed 2012 CDM adjustment provided Atikokan commits to/is required to establish an LRAM variance account as set out in the Guidelines. Otherwise, in VECC's view a reduction to 0.1 GWh of CDM savings should be adopted to recognize both the under-achievement in 2011 and the fact that any programs introduced in 2012 will not have a full year's effect in that year."

45. Neither Board staff nor VECC take issue with Atikokan's 2012 customer count.

- *Atikokan's reply*

46. Atikokan agrees with VECC's submission that the regression model that supports the proposed load forecast in the Application has a high Adjusted R-Squared value and all the proposed explanatory variables are both statistically significant and have intuitively correct coefficients. As a result and even though it is a higher forecast than the one proposed by Board staff, it is Atikokan's submission that the 2012 test year load forecast and customer/connection forecast as proposed in the Application should be approved by the Board. In addition, in order to address the LRAM issue raised by VECC, Atikokan commits to following the Board's recently released CDM Guidelines in this regard.

Other Revenues

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[6] Exhibit 3/Tab 2/Schedule 1, pages 7-8
[7] EB-2012-0003, April 26, 2012, page 11

47. In its Application, Atikokan forecasted other operating revenues as $125,235 for the 2012 Test Year.

- *Board staff and VECC submissions*

48. Board staff submits that "In response to various interrogatories, Atikokan Hydro has explained the volatilities and the drivers on year-over-year differences. Board staff submits that the utility has adequately explained apparent discrepancies, which include incorrect accounting of amounts in some years, and takes no issue with Atikokan Hydro's forecast for Other Operating Revenues in this Application." VECC has one issue with the forecast revenue offset of $125,235 – specifically; VECC requests the addition of $550.00 in anticipated revenues from MicroFIT service charges. This would bring Atikokan's total revenue offsets to $125,785.

- *Atikokan's reply*

49. Atikokan accepts VECC's position and is willing to increase the revenue offsets to $125,785 to include the addition of $550 in anticipated revenues from MicroFIT service charges

4. OPERATING EXPENSES

50. At paragraph 26 of its Argument-in-Chief, Atikokan identified changes to its Service and Base Revenue Requirements that were in part a result of changes in Atikokan's OM&A, amortization and PILs calculations, as well as a revision to Atikokan's Property, Plant and Equipment ("PP&E") calculation. Those adjustments had the following impacts on Atikokan's distribution expenses:

- Amortization expense has been reduced from $197,456 in the Application to $168,793, which includes a PP&E amortization adjustment of $8,500;
- The PP&E Return Adjustment has gone from $0 in the Application to a reduction of $1,813 from the 2012 Test Year revenue requirement;
- PILs expense has been reduced from $17,914 in the Application to $14,087; and
- OM&A has been increased (due entirely to the OMERS adjustment of $45,229) from $1,175,151 in the Application to $1,220,380.

51. Atikokan maintains that that these distribution expense-related adjustments to the 2012 Test Year revenue requirement are reasonable and appropriate, and are supported by the evidence as modified through the interrogatory process.

52. In replying to matters raised by Board staff and VECC related to operating expenses, Atikokan has followed the order of topics in the Board staff submission.

- **OM&A**
- *Board staff and VECC submissions*

53. Board staff indicates that Atikokan forecasted $1,175,151 for OM&A for the 2012 Test Year, representing a 45.25% increase over its 2008 Board-approved OM&A of $809,045. Board staff notes that this amount was increased in the interrogatory process due to increases in OMERS expenses. Board staff acknowledges that the increases are generally necessary and reasonable, but express a concern that there is no real increase in the number of customers served or in energy demand and that Atikokan lost a major customer in 2008. Board staff compared Atikokan to other small Northern Ontario utilities with low undergrounding and express a concern that Atikokan is proposing to increase its OM&A materially when, in Board staff's view, its OM&A is

already the highest among comparable utilities. Board staff goes on to express concerns about other matters including the forecast level of bad debt and application-related costs; and they suggest that productivity improvements should be available because, with line crew being relieved from meter reading duties as a result of smart meters, they will be more available for other capital and operations activities.

54. Board staff do not take issue with Atikokan's proposed staff complement of 9 (representing an increase of one FTE), but note that the staff complement is increasing while the number of customers served is hardly changing, and suggest that "the utility needs to become more focused on dealing with new requirements with its existing complement." VECC submits that there is no compelling reason to support a permanent increase in FTEs.

55. Board staff submits that the Board should impose a 10% reduction in 2012 OM&A, so that Atikokan's 2012 Test Year OM&A would be reduced to $1,100,000.

56. VECC generally supports Board staff, but would further reduce Atikokan's forecasted OM&A. VECC's approach results in an OM&A value of $1,045,274, but VECC submits that a reasonable value is somewhere in the range of $1,025,000 to $1,065,000.

Atikokan's reply

57. Atikokan notes that in choosing values from the interrogatories, Board staff apparently chose to use values from the unaudited and unadjusted values presented in answer to VECC IR#15 as part of the first round of interrogatories. Board staff have used this information and started from the 2011 unaudited actual of $950,000. To that is added the amounts of $45,000 for OMERS and $50,000 as 25% of the regulatory costs for this Application, plus $30,000 for the additional staffing and an allowance for inflation to arrive at their proposed OM&A level of 1,100,000.

58. As discussed above in the context of the effective date for Atikokan's rates, Atikokan's 2010 financial statements were the subject of a "going concern" note inserted by its external auditors. As part of the second round of interrogatories, Board staff requested in IR#64 further information on Atikokan's expected loss for the 2011 year. Atikokan advised that throughout the Application and particularly in the deficiency descriptions, Atikokan had indicated that it faces significant challenges to operate at existing rate levels. Preliminary work on its audited 2011 financial statements showed a significantly greater loss than

forecast in the current Application ($85,000). Revenue in both the Residential and GS<50 kW classes was down in both fixed and volumetric service charges, and revenue for these classes as compared to 2010 would be down by $102,992.

59. Atikokan went on to advise that in terms of the going forward comment, Atikokan expected that with losses greater than forecast, there would be a similar comment to indicate that Atikokan will need to increase its rates or decrease its costs to continue to be viable. Atikokan has reviewed its costs several times. Atikokan is faced with rising costs for many items including operating the smart meters, with the same or fewer customers to bear those costs. The table at page 9 of Atikokan's response to Board staff Interrogatory #64 (shown above in the "effective date" discussion and reproduced below) is derived from some of the working documents that were used in the audited statements. These figures indicate that while costs were reduced by $25,639; revenue was down by $102,922 when comparing 2011 to 2010.

60. Atikokan further submits that the figures Board staff chose to use from Atikokan Hydro's response to VECC IR#15 do not represent updates to similar figures provided in response to Board Staff IR#64. As a result, the table below from Board Staff IR#64 presents a more accurate picture of Atikokan's actual 2011 performance.

		(Note 2)	
Revenue	**2011**	**2010**	**Difference**
Sale of energy	$0	$0	
Distribution revenue	1,076,223	1,146,051	-69,828
Rent from electric property	34,911	34,911	0
Late payment charges	4,809	6,024	-1,215
Miscellaneous revenue	105,748	133,910	-28,162
Demand management program revenue	0	0	0
Interest and dividend income	11,012	14,799	-3,787
Total	1,232,703	1,335,695	**-102,992**
Expenses			
Administration	514,543	450,248	64,295
Amortization	198,823	221,088	-22,265
Billing and collecting	156,366	130,786	25,580
Distribution expense operation	208,516	323,096	-114,580
Distribution expense maintenance	137,495	120,699	16,796
Energy cost	0	0	0
Interest on long-term debt	93,508	83,048	10,460
Other interest expense	4,760	10,685	-5,925

Demand management program expense	0	0	0
Total	1,314,011	1,339,650	**-25,639**

61. Atikokan submits that the following table (Table 1) is a more realistic starting point for 2011 actual OM&A results.

Table 1

Expenses	
Administration	514,543
Billing and collecting	156,366
Distribution expense operation	208,516
Distribution expense maintenance	137,495
Total from audit notes	**1,016,920**

62. However, the completed 2011 audited financial statements have indicated that Billing and Collecting has been reduced from $156,366 to $132,193. All other values have remained the same. Atikokan Hydro understands that this information was not provided as part of the record for the Application but believes it is appropriate to disclose this amount for the purpose of this submission since it is a lower number. Atikokan submits that the following table (Table 2) reflects an even a more realistic starting point for 2011 actual OM&A results.

Table 2

Expenses	
Administration	514,543
Billing and collecting	132,193
Distribution expense operation	208,516
Distribution expense maintenance	137,495
Total from audit notes	**992,747**

63. Consistent with the method proposed by Board staff, Atikokan submits that $45,000 for OMERS and $50,000 as 25% of the regulatory costs for this Application, plus $30,000 for the additional staffing should be added to the 2011 starting point of $992,747. In addition, an amount of $91,173 should be added for smart meters. The following table summarizes Atikokan's submission on the appropriate level of OM&A

Table 3

Expenses	
Administration	514,543
Billing and collecting	132,193
Distribution expense operation	208,516
Distribution expense maintenance	137,495
Total from audit notes	**992,747**
Additional staff costs	30,000
OMERS	45,229
25% of CoS	50,000
Cost of operating smart meters	91,173
Total estimate for 2012 OM&A	**1,209,149**

64. In the Application at Exhibit 4, Tab 2, Schedule 3, Page 1 of 15, table 4-11 the cost of operating smart meters is shown as $107,573. In preparing this submission Atikokan once again reviewed its cost structure in detail and determined that the sum of $16,400 had been included in both the smart meter operating costs and billing costs. In order to address this duplication, the cost of operating smart meters has been reduced to $91,173. For the reasons outlined below, it is Atikokan submits that the amount of $91,173 is incremental above the 2011 actual OM&A value and will not be offset by savings in meter reading costs.

65. Atikokan submits that the proposed level of OM&A, which has been reduced from $1,220,380 to $1,209,149 is reasonable and supported by its evidence. As acknowledged by Board staff, the increases in OM&A proposed by Atikokan are generally necessary and reasonable. Notwithstanding this, Board staff would have the Board apply an arbitrary 10% reduction to Atikokan's OM&A, while VECC would have the Board make greater reductions.

66. Atikokan acknowledges that it is a small utility, and that it is not experiencing significant load or customer growth at this time. However, the requirements to which it is subject, including those related to the maintenance of the safety and reliability of its system and the level of service to its customers, remain notwithstanding minimal or no growth. Put simply, the fact that there are fewer customers on a line does not relieve the utility of any obligations to maintain the line. Similarly, Atikokan is subject to the same administrative requirements, including reporting requirements and filing requirements related to cost of

service and other applications as other larger utilities. In the paragraphs that follow, Atikokan wishes to address a number of the specific items mentioned by Board staff and VECC.

67. Board staff suggested that productivity improvements could result from line crews no longer doing meter reading. Atikokan submits that removing the meter reading function from its line crews will not significantly reduce the need for operating costs. While some of that time will be devoted to capital projects, the line crews' wages must still be paid, and the removal of that function will not reduce employee complement. Atikokan estimates that the average meter reading costs attributed to the line maintainers would have been approximately 48 person hours per month. This would have been in the area of $1700 per month. While as much as possible of this amount would be diverted to capital projects to complete upgrades in infrastructure, meter reading costs will remain in one category or another of OM&A. As a comparison, the cost per month for the back end operations of the Automatic Meter Reading entity (preparing the data for the Operational Data Storage/MDM/R and operating the Local area network for TOU data collection) is $2,000 per month. This service is contracted from Thunder Bay Hydro as a participant in the northwest group of distributors. There will be additional operational costs now that Atikokan Hydro does not read the meters. While reading the meters, the lines staff also completed a line patrol every month. Since this no longer will occur a patrol and inspection of the line will need to be completed at least once per year and the costs related to those activities must be included in OM&A.

68. Board staff has noted that there are no new customers or load, but Atikokan submits that the cost of operating its system does not necessarily change proportionately to number of customers. Line trucks and major equipment must be replaced from time to time regardless of customer load. Poles do not deteriorate at a lesser amount because they are not as heavily loaded. As noted in the Application, Atikokan needs to increase its replacement of existing assets, and with no significant increase in customer numbers, OM&A increases must be reflected in rates charged to existing customers.

69. Board staff also noted that the forecasted regulatory costs for this Application of $200,000 are high for a utility of this size, and submits that there is limited evidence on the record to support the prudence of this level of costs. While Board staff did not propose a reduction in OM&A in this area, VECC proposed a 15% reduction in regulatory costs.

70. In this regard, Atikokan Hydro notes that it completed its own rebasing application in 2006 without external assistance. Board comments encouraged Atikokan Hydro to seek professional assistance in future applications. Board Staff also concluded at the end of a regulatory audit in 2007 that Atikokan Hydro needed to file a Cost of Service application and that it needed external good quality professional assistance in so doing. Atikokan used a different consultant to start its 2008 Cost of Service process. That consultant quit after the application was filed. Atikokan's current consultant came forward and completed the interrogatory process with Atikokan. Board comments after the 2008 cost of service application also indicated that Atikokan needed to improve the quality of its original application. For the current Application, Atikokan retained a consultant with significant experience in electricity distribution rate applications generally, and with experience in respect of Atikokan. Atikokan's consultant in this Application had assumed carriage of the 2008 application after Atikokan's original consultant left, and has assisted Atikokan in other rate-related matters since 2008. Atikokan submits that it was reasonable and cost-effective to retain an experienced consultant who was already familiar with the utility rather than incurring additional costs related to an RFP for these services, and potentially incurring additional time and costs in retaining another consultant who is not familiar with Atikokan. Atikokan offers the following additional comments in this regard:

- In order to control the cost of service to customers Atikokan does not have internal staff that monitors and keeps abreast of all issues related to rate applications;
- In accordance with the filing requirements Atikokan is required to file the same level of information that is expected of a distributor 200 times its size;
- On March 16, 2012, in Procedural Order No. 2, the Board itself acknowledged that Atikokan had responded to a relatively large number of interrogatories; and
- Atikokan requires experienced outside help that understands Atikokan's business and the Board's requirements to adhere to all of those requirements and the Board's deadlines throughout a cost of service rate application process.

71. For all of the foregoing reasons, Atikokan submits that it has acted reasonably and appropriately in the selection of its outside consulting services for this Application.

72. With respect to bad debt, Atikokan submits that bad debt is not predictable, and the amount from year to year is directly proportional to the economic performance of the

service area. Atikokan bills all of its customers monthly, but some of the customers moving in and replacing existing customers are low income families that have a tendency to fall behind and leave the area. Because these families or individuals are low income, Atikokan cannot pursue collections as the low income customers or customers on social assistance are exempt.

73. Additionally, as noted throughout the Application, Atikokan's service area is not compact. As noted in Atikokan's response to Board staff Interrogatory #9, the street light count is high for the population. An extended version of the table from IR #9 is below.

	Customers	Street Lights	Street Lights/ cust	Hydro Poles	Hydro Poles / customer
Atikokan	1674	635	0.379	1289	0.770012
Fort Frances	3795	1054	0.278	1759	0.463505

74. As noted throughout various areas of the application, Atikokan Hydro has fewer customers than it did in the past. Atikokan Hydro understands that it has fewer customers per pole than at least one other of its comparators. Unfortunately a shrinking customer base or a declining load has no effect on the infrastructure and its continuous need for maintenance and operation expenses.

75. While 2011 unaudited expenses are below those originally forecast, they are both unaudited and not necessarily in line with past year averages. In many cases where population is dropping, the reduction is the result of reduced household size, so the infrastructure stays the same (very few young people have been able to find employment in Atikokan's service area, so they have moved out of their families' homes and out of the service area).

76. The map provided in Appendix "C" (page 28) of Atikokan's original Application clearly shows that many of the streets do not have houses behind them, and that the town is spread out over a large geographic area. It would be possible to serve twice the number of customers with the existing infrastructure, but those customers do not exist and are not forecast to enter the service area. The result is ongoing and increasing operation and maintenance costs spread over a small number of customers.

77. With respect to Atikokan's staff complement, Atikokan would agree with VECC submission [page 8 paragraph 5.7] that the increase in FTE is only temporary. However, this has been reflected in the cost structure submitted in the Application which reflects a staff complement of 8 FTEs. In reviewing the Application at Exhibit 4, Tab 2, Schedule 6, Table 4-24 should have shown 8 instead of 9 total FTEs for 2012. It appears there was a double count on the part time staff number in the total number.

78. In an effort to reduce costs, Atikokan increased the work hours from 35 hours per week to 40 hours per week during its 2010 contract negotiations. This was done to in fact reduce or eliminate overtime within the administration portion of the utility. This has helped reduce some costs, but the Application did include moving a part time position to a full time position resulting in a staff complement of 8 FTEs.

79. Since smart meters have been moved into the 2012 rate base and revenue requirement smart meter expenses that were previously in account 1556 for the operation of smart meters have been included in OM&A.

80. For the foregoing reasons, Atikokan submits that its proposed OM&A amount of $1,209,149 is reasonable and appropriate, and that it should not be subject to the arbitrary reductions proposed by Board staff and VECC.

- **Depreciation**

81. As noted by Board staff in their submission, Atikokan has followed the Accounting for Municipal Electric Utilities in Ontario and the 2006 Electricity Distribution Rate Handbook.[8], and has adjusted the depreciation rates for various classes of assets in accordance with the change to IFRS. Atikokan has estimated a depreciation expense of $168,793 in the updated RRWF filed on April 11, 2011.

- *Board staff and VECC submissions*

82. Board staff notes that "the depreciation expense for the 2012 test year may need to be revised in accordance with any adjustments to rate base and capital expenditures as determined by the Board. Board staff submits that Atikokan Hydro should file sufficient evidence, such as an updated Capital Asset Continuity Schedule to allow for

[8] Exhibit 4/Tab 1/Schedule 13

confirmation of any updated depreciation expense to support its draft Rate Order, when filed."

83. VECC takes issue with the values for the useful lives of assets used by Atikokan in the Application, and submits that Atikokan should be required to use the typical lives found in the Kinectrics Study.

- *Atikokan's reply*

84. Atikokan submits that moving to the typical lives found in the Kinectrics Study would cause depreciation expense to increase. The increase would occur since the useful life on transformers would be shortened and there would not be an offset from any increase in useful life on other assets. Atikokan submits that the values used in the Application are reflective of the useful lives for Atikokan Hydro assets and are beneficial to the customer.

- **PILs, the *Green Energy Act* and LEAP**
- *Board staff submissions*

85. With respect to PILs, Board staff take no issue with Atikokan's methodology (as amended through the interrogatory process) for calculating its 2012 tax/PILs allowance, but note that the calculated value of $17,914 will be subject to adjustment to reflect any changes to Atikokan's capital and operating expenses and other factors the Board may determine in its Decision. Board staff submits that Atikokan should use the same approach to calculate any updated allowance for taxes/PILs to reflect the Board's Decision. Board staff takes no issue with Atikokan's basic GEA Plan. Finally, Board staff submits that Atikokan Hydro's proposal with respect to the Low Income Energy Assistance Program ("LEAP") is compliant with Board policy.

- *Atikokan's reply*

86. Atikokan acknowledges that its PILs calculation may change as a result of the Board's Decision, and confirms that it intends to use the same approach to calculate the allowance to reflect the Board's Decision in the event that the Board makes adjustments to any factors that would affect the tax/PILs calculation.

5. COST OF CAPITAL

87. In its update to Board staff supplemental IR # 78 filed on April 11, 2012, Atikokan reflected the Board's updated Cost of Capital parameters in calculating its Revenue Requirement. Atikokan had originally applied for approval of a weighted average cost of capital of 6.49%. The updated value is 6.09%.

- *Board staff and VECC submissions*

88. Board staff submit that Atikokan's proposal for its Cost of Capital complies with the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* (the "Cost of Capital Report"), issued December 11, 2009 and with Board policy and practice. With respect to Atikokan's long term debt rates, Board staff takes no issue with the proposed rates for debt instruments with a third party bank or with its affiliate, Atikokan Enercom. Board staff also submits that the fixed rate for a note held by the Town of Atikokan is compliant with the policies of the Cost of Capital Report.

89. The following item has been raised by Board Staff, however: "Board staff observes that Atikokan Hydro has adjusted the weighted average long-term debt rate in the RRWF filed in response to Board staff IR # 78 from 4.57% to 4.22%. However, Atikokan Hydro has not documented the reason for this change. Board staff submits that Atikokan Hydro should explain this and shown the calculation in its reply submission."

90. VECC supports the submissions of Board staff with respect to cost of capital.

- *Atikokan's reply*

91. Atikokan's understanding is that neither Board Staff nor VECC opposes Atikokan's proposal, but that they have requested comments on the reason for the change in the weighted average long-term debt rate from 4.57% to 4.22%. Atikokan offers the following comments in this regard:

- When the Application was prepared in the late summer and early fall of 2011, Atikokan assumed the Cost of Capital Parameter Updates for 2011 Cost of Service Applications for Rates Effective May 1, 2011 which were the following:

ROE	9.58%
Deemed LT Debt rate	5.32%
Deemed ST Debt rate	2.46%

- The note held by the Town of Atikokan (the "Town Note") had an actual debt rate of 5.0%. Since this was less than the Board's Deemed LT Debt rate of 5.32%, 5.0% was used in the weighted average rate of return on LT Debt which produced a rate of 4.57%. However, in the Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective May 1, 2012 the Board issued the following deemed rates

ROE	9.12%
Deemed LT Debt rate	4.41%
Deemed ST Debt rate	2.08%

- Since the Deemed LT Debt rate of 4.41% was lower than the 5% actual debt rate for the Town Note, the 4.41% was assumed for the Town Note producing a weighted average rate of return on LTD of 4.22%.

6. COST ALLOCATION

92. In response to VECC Interrogatories 5(a) and (c), Atikokan provided updated revenue to cost ratios. A table of those updated ratios is provided at paragraph 7.1 of the VECC submission, and is reproduced here for the Board's reference:

REVENUE TO COST RATIOS – 2012 Updated Results	
Customer Class	**2012 Revenue to Cost Ratios**
Residential	97.3%
GS<50	128.8%
GS>50	89.0%
Street Lights	75.8%
Total	**100.0%**

93. The only customer class whose revenue to cost ratio is outside of the Board's recommended range is the GS<50 class. The top of the recommended range for this class is 120%, while the updated results of Atikokan's cost allocation calculations shows that class at 128.8%. As VECC notes in its submission[9], "In its response to VECC's interrogatories Atikokan revised its originally proposed revenue to cost ratios for 2012 and is now proposing[10] to:

- Decrease the GS<50 ratio to 120%, and,
- Increase both the GS>50 and Street Lighting ratios to 90.6% (in order to maintain the same overall revenues)
- Hold the Residential ratio unchanged at 97.3%

In the subsequent years (2013 and 2014), Atikokan proposes to maintain the same values for each customer class' revenue to cost ratio.

94. Atikokan confirms that this accurately reflects its current proposal.

[9] VECC submission, paragraph 7.3
[10] VECC IR Round #2 - #5 a) & c)

- *Board staff and VECC submissions*

95. The Board staff submission does not reflect Atikokan's updated approach to cost allocation set out in its response to VECC Interrogatories 5(a) and (c). Instead, the Board staff submission refers to the approach to cost allocation proposed by Atikokan in its Application. At that time, Atikokan was proposing to increase the ratios of the Residential and Street Lighting classes, but not the GS>50 kW class, when reducing the GS<50 class to the upper boundary of the range. Board staff noted that increasing the GS>50 kW ratio would assist in mitigating rate increases in the Residential class.

96. In the VECC submission, "VECC submits Atikokan's proposals are consistent with previous Board Decisions[11] and that the Board should accept Atikokan's proposed revenue to cost ratios for both 2012 and the subsequent years."

- *Atikokan's reply*

97. As noted above, Atikokan confirms that its revised cost allocation proposal is accurately reflected in its responses to VECC Interrogatories 5(a) and (c). Consistent with VECC's submission, Atikokan's submits that its proposals are consistent with previous Board Decisions and that the Board should accept Atikokan's proposed revenue to cost ratios for both 2012 and the subsequent years.

[11] Board Decision EB-2010-0131, page 43

7. RATE DESIGN

98. As noted in Atikokan's Argument-in-Chief, Atikokan made three revisions to rate design-related elements of its Application as a result of the interrogatory process:

- Atikokan has revised its proposed Transformation Allowance Credit to be 10% of the proposed volumetric rate of the GS > 50 kW customer class (please see Atikokan's response to Board Staff Interrogatory #21), so that the proposed Transformation Allowance Credit is now $0.24/kW rather than $0.17/kW as shown in the Application. However, Atikokan has also confirmed in its response to Board staff Interrogatory No.21(c) that "…it would be appropriate to adopt a Transformer Allowance Credit of $0.31/kW based on the cost allocation model results and the fact that the class volumetric rate is significantly higher than any TAC", and Atikokan confirmed in its Argument-in-Chief that it is prepared to adjust its Transformation Allowance Credit to $0.31/kW and, subject the Board's approval of that change in its Decision, will do so in the Draft Rate Order that will be prepared following the issuance of the Board's Decision on this Application.

- Atikokan has updated the typical Residential consumption amount from 800 kWh to 581 kWh per month for the purposes of determining the rate mitigation amount for Residential customers (please see Atikokan's response to Board Staff Interrogatory #24). Atikokan proposed the following revised mitigation measures:

  Step 1: Provide a rate mitigation rate rider for Residential customer of ($0.0086) per kWh to limit the bill impacts to just under 10% for a Residential customer using 581 kWh per month. This rider will defer about $98,000 in distribution revenue for one year and Atikokan Hydro is proposing to book this amount in account 1574 Deferred Rate Impact Amounts for future recovery; and

  Step 2: Defer the disposition of the 2010 Group 1 and 2 deferral and variance account balances until the 2013 IRM application. By the time Atikokan Hydro is preparing its 2013 IRM application, the audited 2011 balances for deferral and variances account should be known. In order to support the rate mitigation plan Atikokan is seeking approval from the Board to bring forward its audited 2011 Group 1 and 2 deferral and variance accounts balance for disposition in its 2013 IRM application.

- Atikokan has updated its RTSRs using the Board's model and the Board's recently approved 2012 Uniform Transmission Rates (please see Atikokan's response to VECC Interrogatory #22).

- *Board staff and VECC submissions*

99. In their submissions Board staff and VECC deal with the following matters:

    - Atikokan's proposed elimination of Unmetered Scattered Load and Sentinel Lighting customer classes (Board staff);
    - Atikokan's proposed maintenance of Fixed/Variable Splits, including increasing Monthly Service Charges ("MSCs") that may be above the "ceilings" discussed in the November 2007 *Report of the Board – Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) (Board staff and VECC);
    - Atikokan's proposed adjustment of Retail Transmission Service Rates (Board staff and VECC);
    - Atikokan's revised proposal to increase the Transformer Ownership Allowance to ($0.31)/kW (Board staff and VECC); and
    - Atikokan's Loss Factors (Board staff and VECC).

100. Atikokan will address each of these items individually below.

    - **Atikokan's proposed elimination of Unmetered Scattered Load and Sentinel Lighting customer classes (Board staff);**

101. With respect to the elimination of the Unmetered Scattered Load and Sentinel Lighting classes, "Board staff notes that the absence of these classes has been reflected in the load forecast and in the Cost Allocation model filed in this Application. Board staff takes no issue with Atikokan Hydro's proposal to eliminate these two customer classes with no customers. Should Atikokan Hydro serve any new USL customers in the future, Board staff submits that these customers be included in the GS < 50 kW class, as has been the treatment by other distributors in similar situations."

- *Atikokan's reply*

102. Atikokan acknowledges that should it serve any new USL customers in the future, these customers will be included in the GS < 50 kW class.

    - **Atikokan's proposed maintenance of Fixed/Variable Splits, including increasing Monthly Service Charges ("MSCs") that may be above the "ceilings" discussed in the November 2007 *Report of the Board – Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) (Board staff and VECC);**

103. With respect to Fixed/Variable splits, Board staff note that Atikokan has proposed to maintain the existing fixed/variable split for all remaining customer classes, as documented in Table 8-3 of the Application. Board staff takes no issue with Atikokan's proposal. VECC asserts that increases in the Monthly Service Charge (the "MSC") where the MSC is already above the "ceiling" are inappropriate (apparently even for the purpose of maintaining the fixed/variable split) and that in those cases, the MSC should be maintained at its current level.

- *Atikokan's reply*

104. Atikokan agrees with the Board staff position in this matter. Atikokan's maintenance of fixed/variable splits even in cases where the MSC is currently above the "ceiling" is consistent with the Board's Report and with the Board's treatment of other distributors in similar circumstances as evidenced by the Board's Decisions on 2011 cost of service rate applications for Hydro One Brampton, Kenora Hydro and Horizon Utilities. For example, this position is supported by the Decision of the Board in the Hydro One Brampton Networks Inc. 2011 cost of service rate application dated April 4, 2011. On page 38 of that Decision, the Board states:

> *"The Board accepts HOBNI's proposed MSC which maintains the current fixed/variable proportions. The Board notes that this is consistent with other decisions in which it has approved applications to increase MSC that were already above the cost allocation ceiling, provided that the increase would not result in a higher revenue from the fixed charge relative to the volumetric charge."*

105. Atikokan respectfully submits that the VECC position is inconsistent with the Board's established approach in this regard and should be rejected.

- **Atikokan's proposed adjustment of Retail Transmission Service Rates (Board staff and VECC);**

106. As noted previously, Atikokan has updated its RTSRs using the Board's model and the Board's recently approved 2012 Uniform Transmission Rates (please see Atikokan's response to VECC Interrogatory #22). Board staff submits that Atikokan's proposal "complies with Board policy and practice, and takes no issue with the proposed updated RTSRs." VECC submits that Atikokan's revised RTSRs should be approved for 2012.

- *Atikokan's reply*

107. Atikokan requests that the Board approve its proposed updated RTSRs.

- **Atikokan's revised proposal to increase the Transformer Ownership Allowance to ($0.31)/kW (Board staff and VECC); and**

108. Board staff concurs with Atikokan's request to increase the TOA to ($0.31)/kW. VECC discusses the change in Atikokan's approach to the TOA, from the maintenance of the ($0.17)/kW originally proposed in the Application, to ($0.24)/kW representing 10% of its proposed GS>50 kW variable charge, and finally to the ($0.31)/kW proposed by Atikokan in its Argument-in-Chief based on the cost allocation model results. VECC goes on to state "that this value is based on the original cost allocation filing and the revised filing produces a value of $0.29 / kW value for the unit cost of transformers. VECC accepts Atikokan's proposal to base the TOA on the results of the cost allocation model. However, VECC submits that the value adopted for 2012 should be based on a cost allocation model that reflects the revenue requirement and load forecast as ultimately approved by the Board."

- *Atikokan's reply*

109. Consistent with the VECC submission, Atikokan submits that the TOA for the 2012 Test Year should be based on the results of the cost allocation model that reflects the revenue requirement and load forecast as ultimately approved by the Board.

- **Atikokan's Loss Factors (Board staff and VECC).**

110. Both Board staff and VECC recommend that the Board approve Atikokan's proposed updated loss factors. Board staff "considers that Atikokan Hydro's methodology for updating its Loss Factors complies with Board policy and practice, and takes no issue with its proposal on this matter." VECC states that "Given that the proposed loss factor represents only a nominal increase over the current value and in the absence of any better approach VECC submits that the Board should adopt Atikokan's proposed loss factor." However, both Board staff and VECC express concerns about Atikokan's loss factors. VECC is "concerned about the the historic increase in loss factors, but notes that there is a subsequent decline starting in 2010…. VECC submits that the Board should adopt Atikokan's proposed loss factor. However, Atikokan should be "put on notice" that the loss factor issue will be followed-up on in its next cost of service proceeding." Board staff acknowledges Atikokan's response to Board staff Interrogatory No. 22(b) in which

Atikokan addressed certain factors that Atikokan submits contribute to the increased losses. Specifically, Board staff stated (in part):[12]

> "It did provide some further explanation of its operating environment that factor into its increased losses. In particular, Atikokan Hydro's distribution system losses are measured from Hydro One Networks Inc's Moose Lake Transformer Station. Electricity flows along 23 km of 44 kV sub-transmission line owned and operated by Atikokan Hydro to the utility's distribution stations. Atikokan Hydro states 'if one was to assume a 4.3% loss for an LDC as sparse as Atikokan Hydro, then it would be reasonable to assume 3% for the 44 kV line. The loss attributed to the 44 kV lines is accumulated on the wholesale meters prior to the power reaching any of our customers.' However, there is no empirical data supporting this response."

111. Board staff notes that Atikokan has indicated in its response to Board staff Interrogatory No. 15(b) that it expects the time spent previously to read meters will be used to work on capital programs that will support the asset management plan. Board staff suggested that this "would be to ensure the continued reliability and safety of the network, and should, in Board staff's submission, also be directed at cost-effective methods of reducing losses within Atikokan Hydro's distribution system. Board staff recommends that Atikokan Hydro be directed to file a report on capital and operations and maintenance activities undertaken to address line losses and to conduct a review of non-technical losses, and the results of these, in the utility's next cost of service application."

- *Atikokan's reply*

112. Atikokan Hydro submits that it's methodology for updating its loss factors complies with Board policy and practice. However, having considered the submissions of Board staff and VECC, Atikokan is willing to file a report on capital and operations and maintenance activities undertaken to address line losses and to conduct a review of non-technical losses, and provide the results of these, in its next cost of service application.

[12] Board staff submission, at p.19

8. DEFERRAL AND VARIANCE ACCOUNTS

113. Board staff address the following issues with regard to Deferral and Variance Accounts:

- Disposition of Group 1 DVA and Group 2 DVA Balances
- Disposition of 2008 and 2009 Group 1 DVA Balances
- Account 1508 – OEB cost assessments and OMERS
- Account 1592 – Sub-account HST / OVAT Input Tax Credits (ITCs)

114. In addition, VECC made submissions on the issue of Account 1508 – OEB cost assessments and OMERS.

115. Atikokan will reply to each item separately.

Disposition of Group 1 DVA and Group 2 DVA Balances

116. As part of its rate mitigation proposal, Atikokan Hydro requested the Board defer the disposition of the 2010 Group 1 and Group 2 DVA balances until it files its 2013 IRM rate application. The 2010 Group 1 DVA balance is a debit amount of $47,612 and Group 2 DVA balance is a debit amount of $202,400 as at December 31, 2010.

- *Board staff submissions*

117. Board staff submit that Atikokan's 2013 IRM rate application proceeding would not be an appropriate forum for the Board to review the Group 2 DVA balances, since they require a review for prudence, and may require closer examination that would lengthen the review of the IRM application as a whole.

118. Board staff submits further that there is a concern with Atikokan's financial viability if the DVA balances are not disposed in this proceeding given the not immaterial debit balance. The recovery for the amounts related to Atikokan's 2010 DVA balances may help enhance Atikokan Hydro's cash flow given the debit balance of the Group 1 and Group 2 accounts.

- *Atikokan's reply*

119. Atikokan suggests that this issue relates more to rate mitigation and should be addressed by the Board as part of that issue.

Disposition of 2008 and 2009 Group 1 DVA Balances

120. In its Decision in EB-2010-0064 regarding Atikokan's 2011 IRM rate application, the Board accepted Atikokan's proposal to address the disposition of the 2008 and 2009 Group 1 Deferral and Variance Account balances, stating:

> A) For the 2008 Group 1 account balances, the approved 2010 (EB-2009-0212) rate riders would continue until April 30, 2012. These rate riders are expected to refund Atikokan Hydro's customers $120,510 (approved on interim basis in EB-2009-0212) of the $247,027 (revised in EB-2010-0064) owed to them.
>
> B) For the 2009 Group 1 account balances, the $138,360 owed by customers would not be disposed until after April 30, 2012. As of May 1, 2012 the remaining amount of the 2008 balances owed to the customers (i.e. $247,027 minus $120,510 = $126,517) would be used to offset the 2009 balances of $138,360 owed to Atikokan Hydro.
>
> The Board directs Atikokan Hydro to track the residual balance (i.e. the difference between the 2008 interim balances versus the 2008 final balances, and the 2009 account balances) at the account level such that the future disposition of the residual amounts by account will reflect the allocation methodology prescribed in the EDDVAR Report, and the disposition of the global adjustment sub-account balance will apply to non-RPP customers.

121. Through interrogatories, Board staff asked Atikokan to confirm if it had tracked the residual balance (i.e. the difference between the 2008 interim balances versus the 2008 final balances, and the 2009 account balances) at the account level per the Board Decision EB-2010-0064. [13] Board staff also asked Atikokan Hydro to update its DVA continuity schedule to reflect the Board direction in its EB-2010-0064 Decision.[14] In its response to Board staff interrogatories, Atikokan Hydro stated that it misinterpreted the Board's Decision (EB-2010-0064) regarding the treatment of 2008 and 2009 account balances. Subsequently, the utility updated the continuity schedule on April 11, 2012.

- *Board staff submissions*

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[13] Board staff interrogatory #31
[14] Board staff interrogatories #32 and #33

122. Board staff submits that the revised DVA continuity schedule that was filed on April 11, 2012 correctly reflects the Board Decision in EB-2010-0064. Board staff further submits that any variances between the reported RRR and December 31, 2010 DVA balances are immaterial.

- *Atikokan's reply*

123. Atikokan is in agreement with Board staff's submission on this issue.

Account 1508 OEB cost assessments and OMERS

124. Atikokan recorded a debit principal balance of $9,985 for the OEB cost assessments in Account 1508 sub-account Other Regulatory Assets Cost Assessment for the period of 2006 to 2009. Atikokan also recorded a debit principal balance of $149,054 for pension costs contributions to OMERS in Account 1508 sub-account OMERS for the period of 2006 to 2011.[15] The total cost that Atikokan recorded under sub-accounts of Account 1508 is $159,039. Atikokan confirmed that the costs for OEB cost assessments and pension costs contributions to OMERS were not included in Atikokan's 2008 Cost of Service rate application and therefore were not recovered in the 2008 rates.

125. In response to interrogatories, Atikokan has confirmed that it has now included the 2012 OEB Cost Assessment and the OMERS cost in its 2012 operating expenses to be recovered through its 2012 distribution rates.

- *Board staff and VECC submissions*

126. As outlined in the Board staff submission, Board staff submits that the Board may wish to consider the following two options:

  - *Option 1 – Not approve the recovery of prior years' OEB cost assessments and pension costs contributions to OMERS*
  - *Option 2 – Approve the recovery of prior years' OEB cost assessments and pension costs contributions to OMERS*

127. VECC submits that Atikokan should not be required to absorb the entire cost of its failure to fully comprehend the regulatory accounting scheme. VECC states that both the Utility and the Regulator share responsibility for this error. Small utilities, like Atikokan, are more at risk in trying

[15] Board staff interrogatories #36 and Deferral and Variance Accounts Continuity Schedule filed on April 10, 2012

to meet myriad of regulatory rules set by a number of agencies and governments. The Board is responsible for communicating its requirements and is resourced to subsequently monitor and audit “at risk” utilities such as Atikokan. It is unfortunate that the error was not uncovered earlier and its discovery in this proceeding demonstrates the on-going value of public hearings to scrutinize utility costs.

128. In VECC’s submission, Atikokan should recover of only a portion of these costs. VECC asserts that this solution recognizes the failed responsibility of Atikokan while avoiding taking punitive action for what amounts to an administrative error.

129. VECC asserts that issues of intergenerational inequities are magnified in this case because of the decline in customers since 2006. A simple allocation of these costs would result in the remaining customers absorbing the costs for those customers who have left the system. VECC suggests a proration of the amounts based on the 2006 customer count. The first step in this process would be to allocate the entire amount based on 2006 customer numbers and volumes. Since the GS > 50 class has lost approximately 28% of its customers since 2006 the amount recoverable by this class would then be reduced this amount. Likewise the intermediate class would be allocated an amount given there was one customer in that class in 2006. As there are no customers currently in this class these costs would not be recovered by Atikokan

- *Atikokan’s reply*

130. Atikokan submits that the Board should approve Option 2 as presented by Board staff. Atikokan has incurred the costs with respect to both OEB cost assessments and pension costs contributions to OMERS and has been tracking these costs since 2006. In addition, these costs are not controllable by Atikokan. While Atikokan may have erred in incorrectly following the requirements set out in the APH for recovery of the OEB cost assessments and pension costs contributions to OMERS, Atikokan respectfully submits that these costs are fair and reasonable; they were not included in the 2008 rates; and they should be collected from customers. Atikokan has proposed to correct the issue on a going-forward basis in this Application.

131. However, in the alternative the method of recovery presented by VECC may be a fair way to address the issue. If the Board were to adopt such a method Atikokan would need further details on how to implement the VECC approach.

Account 1592 Sub-account HST / OVAT Input Tax Credits (ITCs)

132. Atikokan states that Account 1592 Sub-account HST / OVAT Input Tax Credits (ITCs) has a credit balance of $15,431 as of December 31, 2010 and 50% of this balance which is $7,716 is refundable to the ratepayers.[16]

- *Board staff submissions*

133. Board staff takes no issue with the calculation of the Account 1592 Sub-account HST/OVAT Input Tax Credits (ITCs) balance. However, Board staff notes that Atikokan has not included the credit balance of $7,716 in its Deferral and Variance Continuity Schedule under the Account 1592 Sub-account HST/OVAT Input Tax Credits (ITCs) and submits that this amount should be included in the 2010 DVA balances as at December 31, 2010 and refunded to the customers.

- *Atikokan's reply*

134. Atikokan is in agreement with Board staff's submission on this issue.

[16] Response to Board staff interrogatory #69

9. OTHER MATTERS:

Account 1562 – Deferred PILs

135. In its Argument-in-Chief, Atikokan stated that it had revised its Account 1562 PILs Continuity Schedule to reflect the collection of Board-approved PILs beginning May 1, 2002. This results in a balance for account 1562 of $29,597. Please see Atikokan's response to Board Staff Interrogatory #54. In that Interrogatory, Board Staff noted that in its PILs 1562 continuity schedule, Atikokan recorded its entitlement to the 2001 PILs proxy starting on October 1, 2001 and the 2002 PILs proxy on January 1, 2002. However, Board Staff went on to state that Atikokan had submitted a revised 2002 rate application dated March 28 and April 3, 2002, and that due to its amended application for rate adjustment, the effective date of the 2002 rates including the 2001 and 2002 proxies was delayed to May 1, 2002 at the request of Atikokan. Board Staff asked Atikokan for regulatory references to support starting the PILs entitlements earlier than May 1, 2002, and asked whether Atikokan had considered that its entitlement to the 2001 and 2002 PILs proxy should not begin before May 1, 2002 given the delay caused by filing a revised 2002 application.

136. In its response, Atikokan confirmed that the PILs continuity schedule filed in the current Application did not reflect the fact that its 2002 rates (which included certain 2001 and 2001 PILs amounts) did not become effective until May 1, 2002. In order to correct this oversight, Atikokan provided a revised Account 1562 PILs Continuity Schedule, which assumed that collection of the approved PILs began May 1, 2002. In its response to Board Staff Supplementary Interrogatory #76, Atikokan explained why its proposed approach to Account 1562 was appropriate and consistent with the Board's approach in its combined proceeding in this regard (EB-2008-0381).

- *Board staff submissions*

137. In summary, Board staff states that Atikokan Hydro voluntarily chose to implement unbundled rates including the first and second tranches of MARR, and PILs tax expense, on May 1, 2002. Board staff submit that Atikokan should pro-rate its PILs tax proxy entitlements in the same time period as it billed its customers for the changed unbundled rates as described in the following paragraph.

138. The 2001 PILs proxy included in 2002 rates was $7,668. The 2002 PILs proxy was $32,754

and the combined total was $40,422.[17] The period from May 1, 2002 through March 31, 2004 contains 23 billing months. The pro-rated PILs proxy for this 23-month period using the twelve-month total of $40,422 is $77,476. ($40,422/12)*23) During this same period, Atikokan Hydro billed its customers and recovered $75,246 of PILs.[18] Board staff observes, from the Ministry of Finance notices of assessment filed in this proceeding, that Atikokan Hydro did not pay any PILs to the government for the period 2001 through 2006.

139. Board staff submits that the alternative proffered by staff of calculating the PILs proxy with effect from May 1, 2002 is equitable to the ratepayers and to the shareholder. If Board staff's suggestion is accepted by the Board, the debit principal balance to be recovered from ratepayers would be approximately $8,222. Board staff estimates interest carrying charges to be $2,260 for the period up to April 30, 2012 based on the restated principal amount of $8,222 for a total to be recovered of $10,482.

140. Board staff submits that this revised debit amount of $10,482 has been calculated in accordance with the regulatory guidance and the decisions issued by the Board in determining the amounts in Account 1562 Deferred PILs.[19]

141. Board staff requests that Atikokan Hydro file active Excel models with its reply submission to facilitate the final review of its evidence.

- *Atikokan's reply*

142. Atikokan does not agree with Board staff's submission on this issue as outlined in the responses to various interrogatories referenced above. However, Atikokan is also aware that this issue has been addressed by the Board in previous decisions and the Board has ruled in favour of the Board staff position. In addition, Atikokan Hydro did not pay any PILs to the government for the period 2001 through 2006. As a result, for the benefit of the customer Atikokan is willing to accept Board staff's position on this issue and agrees the debit principal balance to be recovered from ratepayers would be $8,222. The interest

[17] 2002 Application PILs proxy models; and 2002 RAM sheets 6 and 8; filed on December 15, 2011
[18] Atikokan_PILS_Reconciliation_2001-2012_20111214.XLS
[19] Decisions in Combined Proceeding, EB-2008-0381 – August 12, 2011; June 24, 2011; December 23, 2010; December 18, 2009. Hydro One Brampton, EB-2011-0174, December 22, 2011. Whitby Hydro, EB-2011-0206, December 22, 2011. Staff Discussion Paper, August 20, 2008. Sioux Lookout EB-2011-0102, April 19, 2002, page 12.

carrying charges on this principal amount for the period up to April 30, 2012 would be $2,260 for a total of $10,482. As part of this submission, Atikokan Hydro has filed the active Excel models which support this amount.

Smart Meters

143. Atikokan has updated the calculation of its proposed Smart Meter Disposition Rider (SMDR) and its allocation of smart meter costs so as to provide for class-specific SMDRs (please see Atikokan's response to Board Staff Interrogatory #38). In its Application, Atikokan had proposed a uniform SMDR of $3.54/metered customer/month for 36 months. As part of its response to Board Staff Interrogatory #38, Atikokan filed a revised version of the Board's Smart Meter Model that indicated the uniform SMDR should be $3.78/metered customer/month for 36 months.

144. In their Interrogatory #42, Board Staff discussed the Board's Guidelines with respect to smart meter cost recovery (G-2008-0002 and G-2011-0001) and referred (in part) to the following comment from the Board in G-2011-0001:

> "The Board views that, where practical and where the data is available, class specific SMDRs should be calculated based on full cost causality. The methodology approved by the Board in EB-2011-0128 [PowerStream's 2011 smart meter disposition application] should serve as a suitable guide. A uniform SMDR would be suitable only where adequate data is not available."

145. Board Staff sought Atikokan's views as to whether there are differences in the costs of smart meters deployed between the Residential and GS < 50 kW customer classes and, if there were material differences, Board Staff requested that Atikokan provide a proposal for allocating the costs between classes based on cost causality and calculating class-specific SMDRs.

146. In its response, Atikokan confirmed that there are differences, and provided a calculation of the following class-specific SMDRs:

Residential:	$3.66/metered customer/month
GS < 50 kW:	$4.17/metered customer/month
GS > 50 kW:	$7.29/metered customer/month

147. Having considered this matter, Atikokan submits that the class-specific approach to SMDRs

illustrated in its response to Board Staff Interrogatory #42 is more appropriate than a uniform SMDR, and requests that the Board approve the class-specific SMDRs set out above.

- *Board staff and VECC submissions*

148. Board staff submits that outside of Hydro One Networks, Atikokan has the highest per meter cost that the Board and staff have seen to date. The capital cost per meter is higher than seen previously for other utilities. However, Board staff note that smaller utilities may not have the size or density to achieve economies with respect to fixed costs for related infrastructure (communications receivers and transmitters, computer hardware and software) relative to larger urban utilities. Atikokan is a smaller utility that is remote from neighbouring utilities and usage data is communicated over 200 km to Thunder Bay. While the per meter capital costs are high, Board staff submit that there is no substantive evidence that these costs are not reasonable in light of its circumstances. As part of the Northwest Group of utilities, Atikokan complied with O.Reg. 427/06 and the London Hydro process for the procurement and deployment of smart meters.

149. However, Board staff expresses more concern with the deferred OM&A costs, as these were materially revised through responses to interrogatories. Some of these costs may be related to third party costs for consulting, ODS set-up and operations, communications costs and again, Board staff recognizes that a smaller utility may be faced with some diseconomies due to its size. Nevertheless, Board staff admits that it has not seen historical per meter OM&A costs as high as Atikokan Hydro is reporting. For the three year period covered, this amounts to about $45.27 per year or about $3.75 per month per metered customer of OM&A costs alone.

150. The revised OM&A costs, representing a 50% increase over the original proposal, were only filed in responses to interrogatories. These costs are significantly higher than Board staff has seen to date. The response to Board staff IR # 66 documented accounting corrections that Atikokan Hydro discovered in preparing its responses to early interrogatories regarding smart meter costs. However, Board staff submits that there is insufficient support on the record about the nature of the products and services for the requested cost levels. Given the unusually high cost per meter level requested, Board staff suggests that the Board consider a disallowance of 20% of smart meter costs. This would bring the per meter cost to just over $350 – still higher than the Board has seen to date for complete smart meter

deployment. This could be accomplished through a reduction in the OM&A costs to avoid a financial impairment to the meter assets recorded by Atikokan

151. VECC agrees with the submissions of Board Staff in respect to Smart Meters. VECC also agrees that some disallowance should be made to the smart meter costs. However, the 20% suggested by Staff is arbitrary. In VECC's submission Atikokan should be allowed the average costs of its cohort of utilities. In the alternative the Board should undertake an audit of the smart meter program of Atikokan and report publicly its findings. Parties should then be able to make submissions on an appropriate recovery amount.

152. This would mean a delay in the recovery of costs. VECC submits that in the interim Atikokan should be allowed to recover 50% of its proposed smart meter costs. The remaining amounts should be recovered after the Board has considered the smart meter costs of Atikokan's cohort of utilities or until an audit of the smart meter program has been performed by the Board.

153. In addition, Board staff and VECC submit that any smart meter disposition should be in accordance with the revised class specific methodology submitted by Atikokan.

- *Atikokan's reply*

154. Atikokan has considered the comments of Board staff and VECC and reviewed the cost structure associated with the SMDR. In particular, Atikokan has reviewed the incremental OM&A costs associated with smart meters. In the OM&A, there is a cost of $2,100 per month paid to Thunder Bay Hydro for CIS/Billing services. These additional costs resulted from the need for Atikokan to use a new billing system in order to support smart meters. However, it could be argued that these costs are billing costs and not smart meter costs per se. As a result, Atikokan is prepared to remove these costs from the calculation of the SMDR from 2009 to 2011. This will reduce the OM&A from $224,207 to $148,607 which is a 34% reduction in OM&A costs associated with the SMDR.

155. Based on Atikokan's calculations this will reduce the average SMDR from $3.78 to $2.49, which represents a 34% reduction. The resulting class specific SMDR would be as follows:

Residential: $2.39/metered customer/month
GS < 50 kW: $2.81/metered customer/month
GS > 50 kW: $5.38/metered customer/month

156. Atikokan submits that the above proposal represents a significant movement by Atikokan for the benefit of its customers and provides an overall reduction which is greater than the 20% reduction suggested by Board staff. Atikokan would suggest this proposal should also address the concerns raised by VECC.

Stranded Meters

157. Atikokan is proposing a Stranded Meter Rate Rider of $0.39 per month, to be effective for a period of three years, to recover the net book value of $23,375 for conventional meters stranded through replacement by smart meters.

- *Board staff submissions*

158. Board staff takes no issue with the amount that Atikokan is proposing to recover. Board staff also takes no issue with Atikokan's proposal to recover the amount over a period of three years to mitigate the immediate impact on Atikokan's ratepayers.

159. In light of Atikokan Hydro's explanations in response to interrogatories about the connection of customers and types of meters, Board staff takes no issue with Atikokan's proposal for a uniform stranded meter rate rider.

160. However, it appears to Board staff that in Atikokan's proposal, Atikokan is proposing recovery from all of its ratepayers. Board staff submits that the Board's policy and practice, as documented in Guideline G-2011-0001, is that the stranded meter rate rider is to be recovered solely from those classes for which conventional meters became stranded through replacement by smart meters. In the case of Atikokan, this would be the Residential and GS < 50 kW classes. In Board staff's submission, the stranded meter rate rider should not apply to the GS > 50 kW class. Board staff submits that Atikokan should confirm in its reply submission the calculation of the stranded meter rate rider and the customer classes to which it would apply.

- *Atikokan's reply*

161. As outlined in the smart meter model filed with the Board in response to Board Staff IR#38, smart meters for the GS > 50 kW class were included in Atikokan Hydro's smart meter program. As a result, there were stranded meters from the GS > 50 kW class, and Atikokan submits that

the stranded meter rate rider should be applied to the GS > 50 kW class as well, and that it is consistent with the Guideline that this be done.

Transition from CGAAP to MIFRS

162. Board staff address the following issues with respect to Atikokan's transition from CGAAP to MIFRS:

1. Impact of MIFRS on Rate base and Revenue Requirement; and
2. Account 1575 IFRS-GAAP Transitional PP&E Deferral Account

- **Impact of MIFRS on Rate base and Revenue Requirement**
- *Board staff submissions*

163. Board staff is of the view that the increase in OM&A resulting from OMERS expenses is not as a result of the IFRS conversion. However, Board staff submits that the resulting working capital allowance of $6,784 is a legitimate adjustment to the 2012 rate base.

164. Board staff notes that Atikokan changed its capitalization policy in 2010 to no longer capitalize expenses that were not directly related to PP&E. This caused an increase in 2010 administration and general expense. Atikokan Hydro filed a note from its external auditors that indicated that Atikokan's auditors had reviewed the accounting policy and confirmed that the Atikokan's policy is in compliance with the IFRS requirements.[20] Therefore, Board staff take no issue with the adjustments made to update the impact of MIFRS to the rate base and are of the view that working capital would be the same under CGAAP and MIFRS due to the change of capitalization policy that was implemented by Atikokan in 2010.

165. As part of the calculation showing the MIFRS impact on the revenue requirement, Atikokan stated that the amount of $169,035 represents an increase in salaries and expenses as a result of a change by Atikokan in its capitalization policy in 2009 and 2010.[21] Board staff submits that there should not be any impact on OM&A in 2011 and 2012 as a result of the conversion to MIFRS, as Atikokan Hydro had already changed its capitalization practices in 2010 to be aligned with IFRS.[22] Furthermore, Board staff submits that Atikokan Hydro has

[20] Response to Board staff interrogatory #46
[21] Exhibit 4/Tab 2/Schedule 3/pp. 2-3
[22] Exhibit 2/Tab 1/Schedule 1/page 7

made an error in calculation of 2012 amortization expenses by using the figures of 2009 and 2010 OM&A increases. Board staff submits that Atikokan should have quantified the MIFRS impact by considering the change in the useful lives of the capital assets as a result of the conversion. As such, Board staff is unclear of the dollar impact on the 2012 revenue requirement for Atikokan Hydro's conversion from CGAAP to MIFRS due to errors in the utility's calculations.

- *Atikokan's reply*

166. Atikokan agrees with the Board staff position on the adjustments made to update the impact of MIFRS to the rate base. Atikokan has reviewed the comments from Board staff with regard to its calculations of the MIFRS impact on the revenue requirement. Atikokan would agree with Board staff that there should not be any impact on OM&A in 2011 and 2012 as a result of the conversion to MIFRS, as Atikokan Hydro had already changed its capitalization practices in 2010 to be aligned with IFRS.

167. Atikokan notes, though, that Board staff may have been confused with Atikokan's response to Board staff IR#47 and #68. It was Atikokan's understanding that in these interrogatories, Board staff was requesting the impact on the revenue requirement in 2011 and 2012 from a change in Atikokan's capitalization policy in 2010. In Atikokan's view, the impact in respect of which information was being requested was not related to MIFRS since the change in capitalization was done prior to implementation of MIFRS. In other words, those interrogatories were specifically exploring the difference in the 2011 and 2012 revenue requirement arising out of the pre-IFRS change in Atikokan's capitalization policy in 2010. Atikokan believes that it has clearly shown the impact of such a change in response to Board staff IR#68(a). It is unclear to Atikokan where it has erred in the calculations provided in response to Board staff IR#68(a) as suggested by Board staff.

Account 1575 IFRS-GAAP Transitional PP&E Deferral Account

- *Board staff submissions*

168. According to Board staff, Atikokan stated that the balance for closing net PP&E between CGAAP and MIFRS is a credit balance of $34,002. Atikokan proposed to amortize the

balance over a four year period.[23] As a result, the annual amortization amount is a credit balance of $8,500 (i.e. $34,002/4). Atikokan calculated the return on the rate base using the average of the opening and closing balance of the PP&E account in 2012[24] (i.e. ($34,002+$25,501)/2 * 6.49%). Atikokan updated the return on rate base from 6.49% to 6.09% in its AIC.[25]

169. Board staff takes no issue on the credit balance of $34,002 as the difference in the closing PP&E deferral account balance between CGAAP and MIFRS and the amortization period of 4 years. However, Board staff notes that the return on rate base of $1,813 was calculated using the average of the opening and closing balance of the PP&E for 2012[26] (i.e. ($34,002+$25,501)/2 * 6.09%). Board staff submits that Atikokan Hydro did not calculate the return on the rate base associated with the deferred balance for difference in closing net PP&E accurately. Instead, Atikokan Hydro should use the PP&E closing balance of $34,002. Board staff submits that Atikokan Hydro should update the calculation for the return on the rate base in the preparation of the draft Rate Order, and should document this in that filing.

- *Atikokan's reply*

170. As outlined in the response to Board staff IR#74(a), consistent with the calculation of average rate base for 2012, Atikokan submits that the calculation of return on rate base for the PP&E deferral account is the average of the opening and closing balance of the PP&E account in 2012 times the rate of return on rate base. However, the resulting difference in return on rate base between the positions of Board staff and Atikokan is less than $260. Since this is such an immaterial difference, Atikokan is willing to accept Board staff position in this regard.

Rate Mitigation

171. In its Application, Atikokan proposed to mitigate the impacts to customers resulting from its proposed rates. Atikokan has proposed to limit bill increases to no more than 10% for a typical Residential customer consuming 800kWh per month through the following:

[23] Response to Board staff interrogatory #50
[24] Response to the Board staff interrogatory #74
[25] Argument-in-Chief P10
[26] Response to the Board staff interrogatory #74

- Deferral of the disposition of all Group 1 and Group 2 DVAs, except for Smart Meter accounts 1555 and 1556, until 2013; and

- Approval for a credit rate rider to reduce the bill impact based on a consumption of 800 kWh per month to no more than 10%. The amount of the credit would be tracked in a DVA for which Atikokan was seeking approval, with the balance to be disposed of in a subsequent rate application.

172. In response to Board staff IR #24, Atikokan acknowledged that a typical Residential customer in its service territory uses significantly less than 800 kWh. On average, monthly consumption for a residential customer is 581 kWh, and only about 33% of residential customers use at least 800 kWh per customer, as shown by consumption distribution data. Accordingly, Atikokan proposed to adjust the credit rate rider to mitigate rate impacts so that a customer consuming 581 kWh per month would have a total bill increase, after taxes and the Ontario Clean Energy Benefit, of no more than 10%.

- *Board staff and VECC submissions*

173. Board staff submitted that the rate mitigation proposed by Atikokan Hydro should not be approved and alternative approaches be considered. VECC submitted that Atikokan's rate mitigation plan is reasonable, consistent with previous Board Decisions and should be accepted by the Board.

- *Atikokan's reply*

174. In order to respond to this issue, Atikokan has considered possible outcomes of the Board's disposition of this Application. In the event that the Board reduces Atikokan's approved revenue requirement from the level proposed in the Application (as revised through the interrogatory process and final submissions), Atikokan submits that it may still be necessary to have a degree of mitigation in order to limit the bill increase to the typical Residential customer to 10%. Atikokan believes that a mitigation plan is appropriate to protect the interests of the customer, and that its proposed approach is both reasonable and appropriate, and should be approved by the Board in the event that the Board approves a revenue requirement that generates bill impacts of over 10% for that customer profile.

CONCLUSION

175. For all of the foregoing reasons, Atikokan respectfully submits that the revenue requirement and rates and charges (including the proposed riders) set out in the Application, as modified by Atikokan's responses to the interrogatories discussed in its Argument-in-Chief and subject to any further revisions discussed above, are just and reasonable, and requests that they be approved by the Board.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 24TH DAY OF MAY, 2012.

ATIKOKAN HYDRO INC.

Wilf Thorburn

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Wilf Thorburn, CEO and Secretary-Treasurer